ISO Study of Operational Requirements and Market Impacts at 33% RPS

Proposed Methodology

and

Selected Simulation Results available as of August 24, 2010

Presentation Slides

(includes some modifications to slides already posted)

CPUC Workshop on

CAISO and PG&E Renewable Integration Model Methodologies

August 24, 2010

Contents of Presentation

Morning:

1. Objectives and Approach of 33% RPS study
2. Some Basic Operational and Market Definitions and Processes
3. Common Assumptions and Data Inputs into All Modeling Stages
4. Methodology for Operational Requirements Simulations (Step 1)
5. Operational Requirements Simulation Selected Results and Interpretation

Afternoon:

1. Methodology for Production Simulations (Step 2)
2. Status of Production Simulation Results
3. Next Steps

SECTION 1:
STUDY OBJECTIVES AND APPROACH

California ISO
Your Link to Power

Objectives (1)

1. Identify operational requirements and resource options to reliably operate the ISO controlled grid (with some assumptions about renewable integration by other Balancing Authorities) under 33% RPS in 2020
   - Estimates of hourly and sub-hourly integration requirements (measured in terms of operational ramp, load following and Regulation capacity and ramp rates, as well as additional capacity to resolve operational violations)
   - Consideration of additional variables that affect the results
     - Impact of different mixes of renewable technologies and other complementary policies
     - Impact of forecasting error and variability

Objectives (2)

2. Inform market, planning, and policy/regulatory decisions by the ISO, State agencies, market participants and other stakeholders

   - Support the CPUC to identify long-term procurement planning needs, costs and options
   - Inform other CPUC, and other State agency, regulatory decisions (Resource Adequacy, RPS rules, once through cooling (OTC) schedule, and so on)
   - Inform ISO and state-wide transmission planning needs to interconnect renewables up to 33% RPS
   - Inform design of ISO wholesale markets for energy and ancillary services to facilitate provision of integration capabilities

Study Approach

- Modeling assumptions and methods developed through a cooperative stakeholder effort
  - Case definitions proposed in fall 2009 by CPUC and an inter-agency team supporting the California Clean Energy Future (CCEF) initiative (CPUC, CEC, CARB and CAISO)
  - Stakeholder and steering committee process to identify assumptions, review methods, and validate results
- Portions of analytical work performed by subset of stakeholder group
- Data can be fully shared (no proprietary data or models used)

A Phased Study Process

- Phase 1
  - Largely focused on defining operational requirements and addressing those requirements with existing and new conventional fossil generation – Gas Turbines and/or Combined Cycle Units (more details on next slides)
- Phase 2
  - Address same operational requirements with combination of conventional fossil generation resources, new non-generation resources – storage, demand side response – and renewable resource dispatch through solar and wind control

- This presentation includes initial results of Phase 1, which is ongoing

Study Approach – Overview of Modeling Tools Utilized and proposed for LTPP methodology

- *Step 1* – Statistical Simulation to Assess Intra-Hour Operational Requirements
  - Estimates added intra-hour requirements under each studied renewable portfolio due to variability and forecast error
  - Calculates the following by hour and season: Regulation Up and Regulation Down capacity, load-following up and down capacity requirements, and operational ramp rate requirements
- *Step 2* – Production Simulation
  - Dynamic optimization model that simulates system least-cost commitment and dispatch of resources to meet load, ancillary services and other requirements in an hourly time-step.
  - Uses Step 1 Regulation and load following capacity results as additional requirements to meet intra-hourly requirements
  - Calculates the following by hour and season: production cost-based energy prices, emissions, energy and ancillary services provided by units, violations of system constraints and additional capabilities required to eliminate those violations

Study Approach – Interpretation of Results

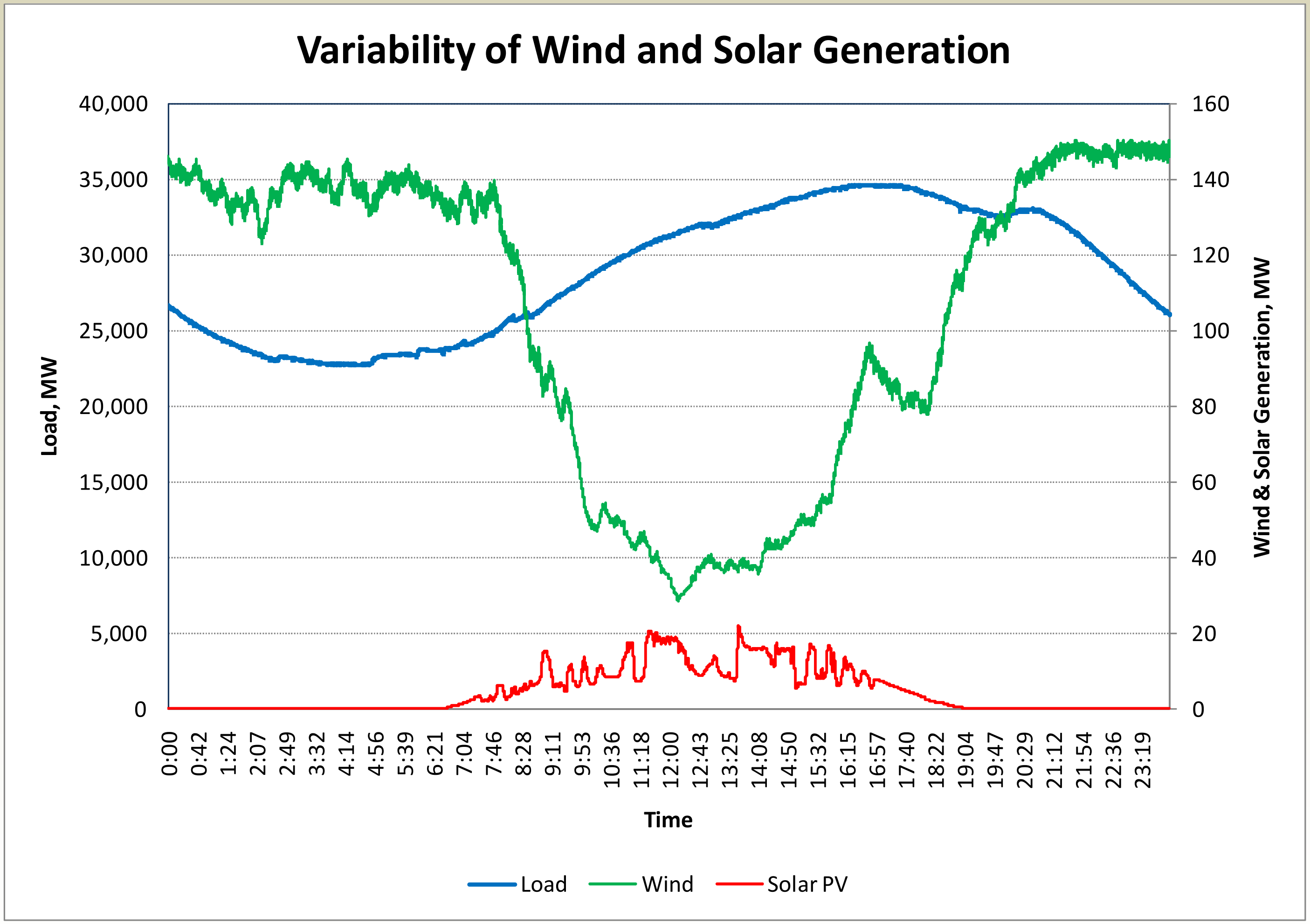
- Simulation results need careful interpretation (discussion in following slides)
- The simulation model methods are well understood and supported; full technical documentation is available
- However, the models are complicated and have a large number of inputs and outputs
- Sensitivity analysis gives further insight into results
- Observation and conclusions should be reserved until the final results are available

SECTION 2: SOME OPERATIONAL AND MARKET DEFINITIONS AND PROCESSES

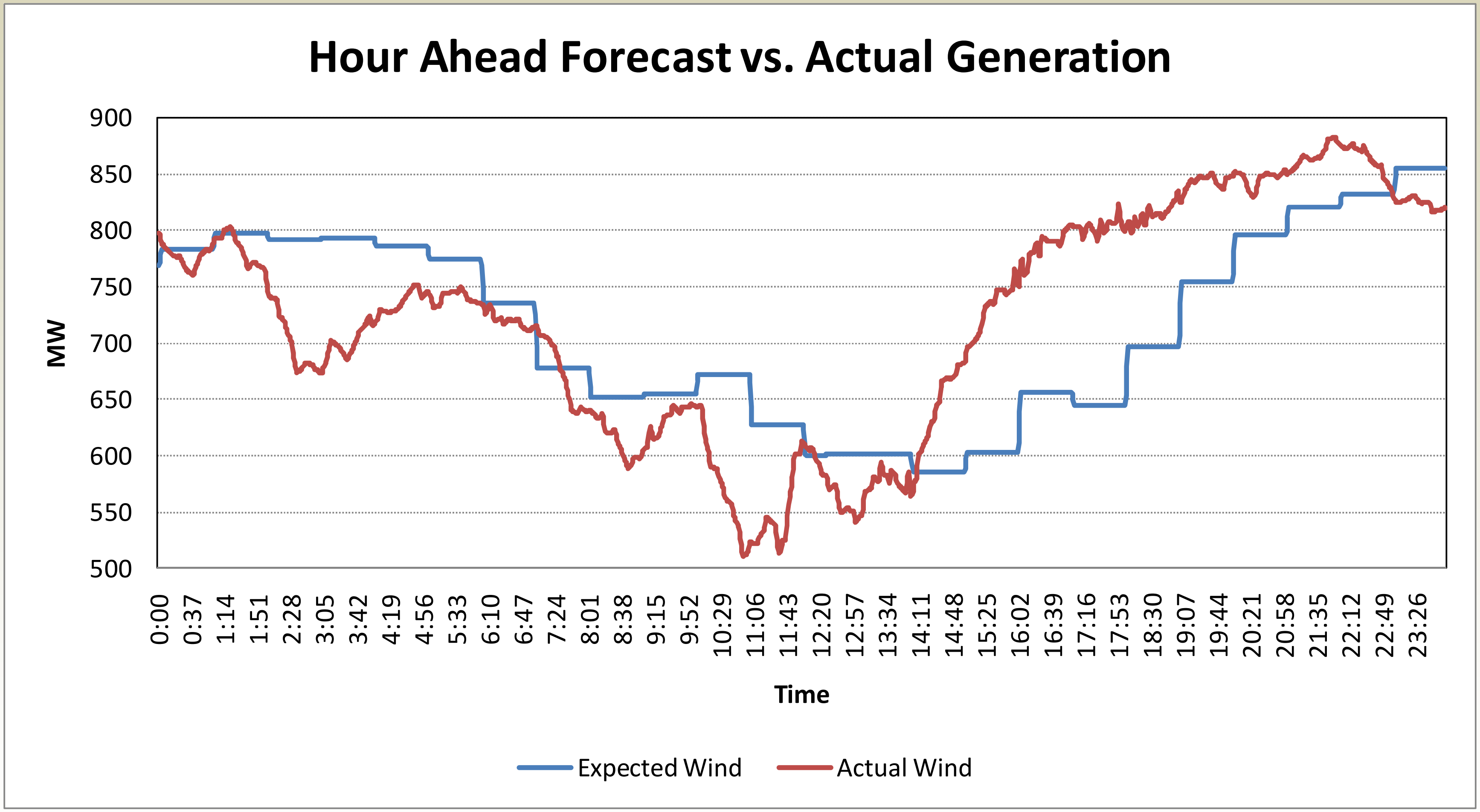
Variable Energy Resources have the Following Characteristics that Affect System Operations

- Variability of fuel source (wind, sun) leads to variable supply
- Higher forecast errors than load, particularly in the day-ahead and hour-ahead time-frame
- Generally not available for dispatch control by the ISO due to technology constraints and regulatory/contract incentives

Variability of Generation – minute-by-minute production variability over the day of a 150 MW wind plant and a 24 MW Solar PV plant



Forecast Error – Hour ahead forecast vs. actual wind generation on June 24, 2010



Overview of Key Operational Impacts being Studied

- Increased frequency and magnitude of system ramps across various time-frames (minutes, hours)
- Increased load-following up and down requirements (intra-hourly deviations from hourly schedules), perhaps leading to needs for additional reserves
- Increased requirements for Regulation Up and Regulation Down (minute by minute requirements within five minute dispatch intervals)
- Increased frequency and magnitude of overgeneration conditions (hours)

Overview of ISO day-ahead and real-time scheduling processes

- The ISO's integrated market and scheduling procedures are ordered as follows:
  - Pre-day-ahead commitment decisions (mainly for long-start units);
  - Day-Ahead Market (DAM), including the Integrated Forward Market (IFM) and the Residual Unit Commitment (RUC), both of which clear on an hourly basis;
  - The Hour-Ahead Scheduling Procedure (HASP) that schedules supply and demand at the inter-ties on an hour-ahead basis; and
  - The Real-Time Market – a set of concurrent unit commitment and dispatch procedures that result in the 5-minute real-time dispatch of internal resources and dynamically scheduled imports.

Start-Up Times (mins) of ISO Generation Fleet and Pumped Storage in 2010

Generation Type		Start-up Times (minutes) by Category					
		ST < 10	10 ≤ ST < 120	120 ≤ RR < 300	300 ≤ RR < 10,800	unknown	Total MW
Non-OTC Units	Combined Cycle		174	1,241	11,717		13,132
	Dynamic Schedule				3,650	1,026	4,676
	Gas Turbine	1,261	2,161	191		4,317	7,929
	Hydro	4,908	1,382	486		640	7,416
	Other	352	294	377		636	1,660
	Pump/Storage	2,232					2,232
	Recovery	19	35	114		37	206
	Steam	267	169	221	1,760	430	2,847
	Not specified	360	114	19		1,672	2,165
Non-OTC Unit Total		9,400	4,329	2,649	17,127	8,759	42,263
OTC units	Combined Cycle			109	491		600
	Gas Turbine					15	15
	Steam				15,127	2,446	17,573
OTC Unit total				109	15,618	2,461	18,188
All Units Total		9,400	4,329	2,758	32,745	11,220	60,451

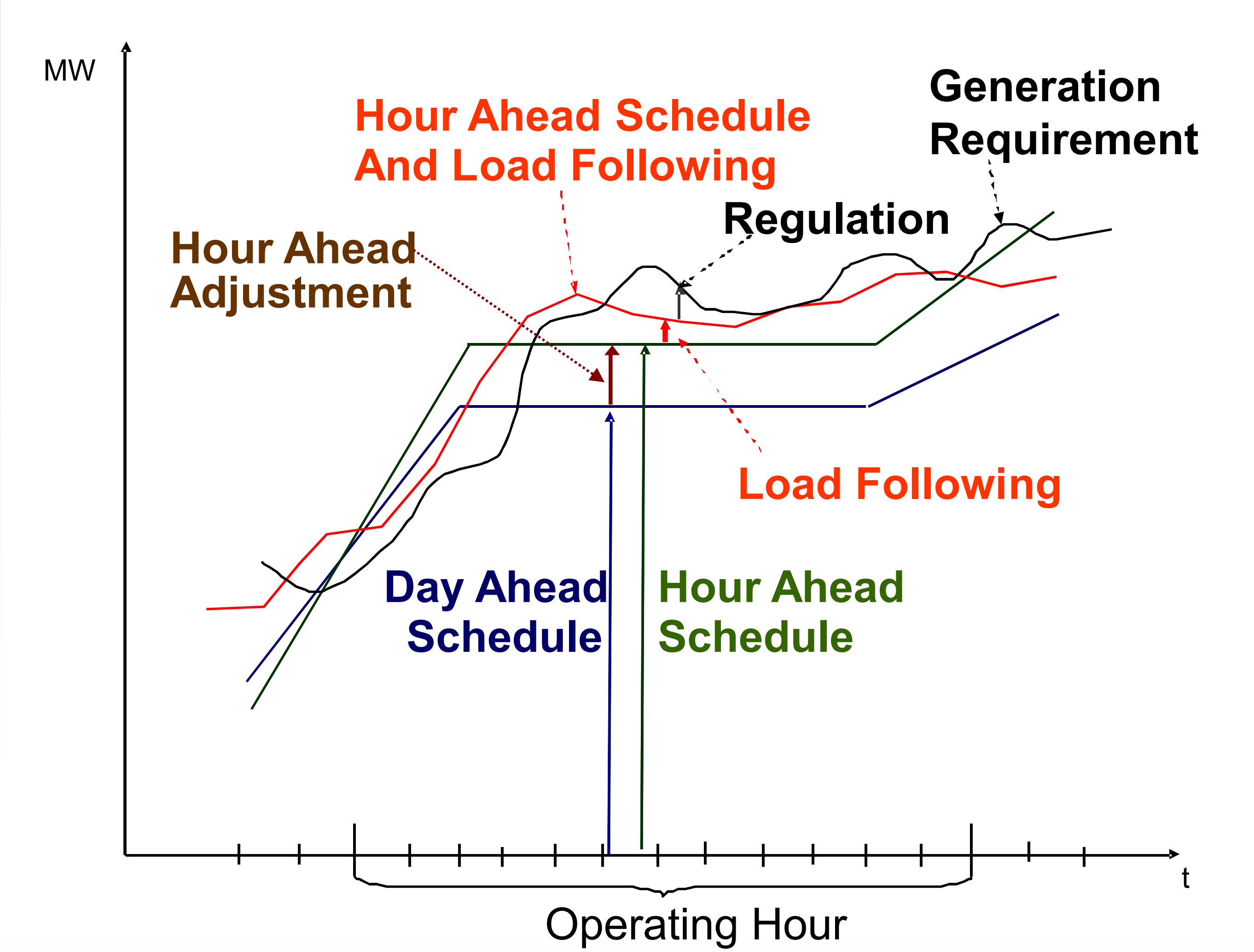
Note that the 33% RPS study models a generation fleet in which most OTC units are replaced and new CCs and GTs are added; in addition the 33% RPS study uses some generic unit data

Ramp Rates (MW/min) of ISO Generation Fleet and Pumped Storage in 2010

Generation Type		Ramp Rate (MW/min) by Category						
		RR < 0.5	0.5 ≤ RR < 1	1 ≤ RR < 5	5 ≤ RR < 10	10 ≤ RR < 20	20 ≤ RR	Total MW
Non-OTC Units	Combined Cycle			4,885	4,630	3,617		13,132
	Dynamic Schedule				552	1,746	2,379	4,676
	Gas Turbine	32	68	1,040	4,635	1,601	553	7,929
	Hydro	99	157	427	1,135	1,927	3,671	7,416
	Other	5	4	14	1,633		4	1,660
	Pump/Storage				440		1,792	2,232
	Recovery	61	17	115	13			206
	Steam	357	355	1,328	747	59		2,847
	Not specified	5	6	42	1,568	20	525	2,165
Non-OTC Unit Total		559	607	7,851	15,353	8,970	8,924	42,263
OTC units	Combined Cycle			600				600
	Gas Turbine			15				15
	Steam		354	8,542	5,650	1,516	1,510	17,573
OTC Unit total		0	354	9,158	5,650	1,516	1,510	18,188
All Units Total		559	961	17,008	21,003	10,486	10,434	60,452

Note that the 33% RPS study models a generation fleet in which most OTC units are replaced and new CCs and GTs are added; in addition the 33% RPS study uses some generic unit data

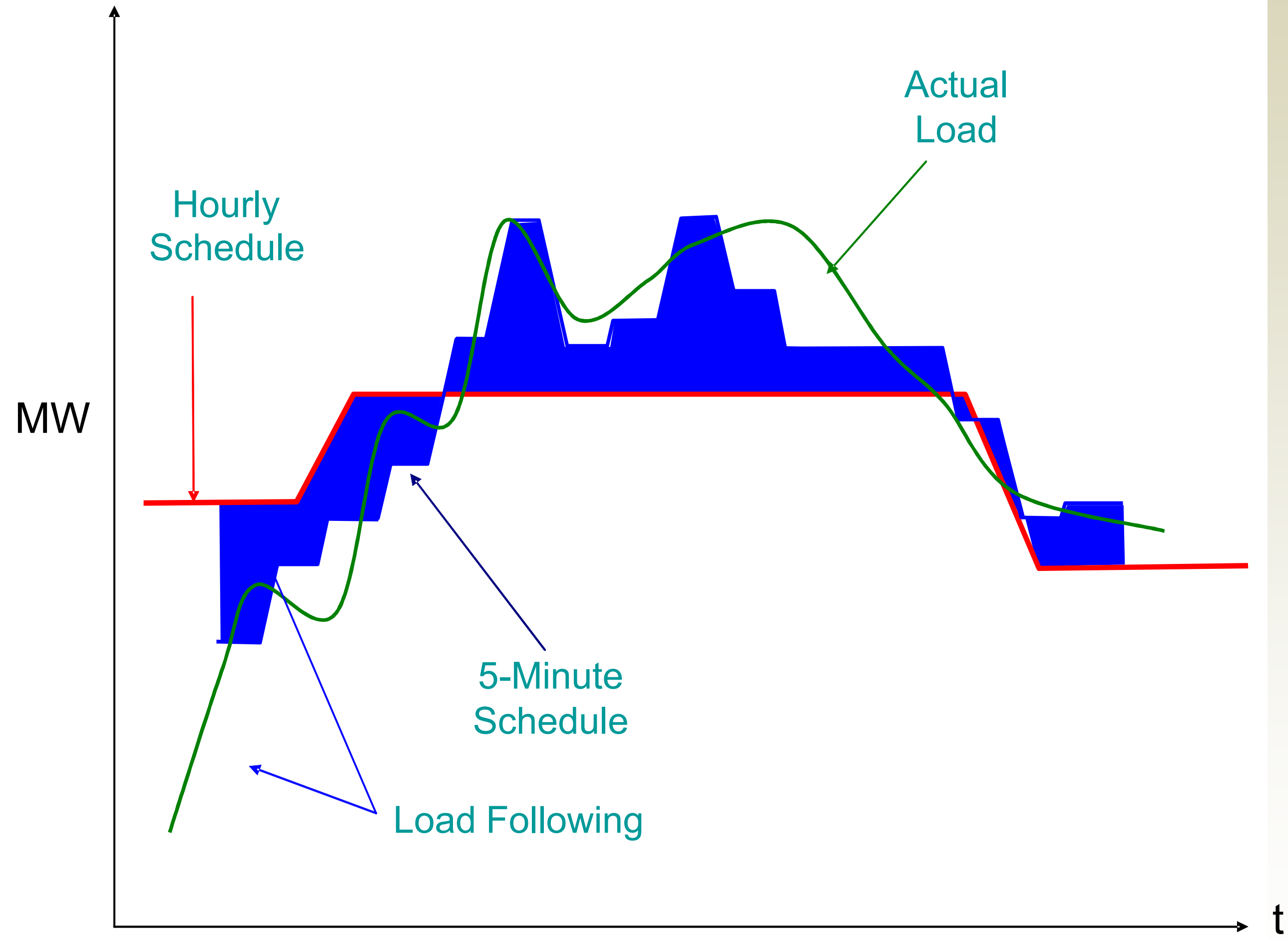
Graphical representation of ISO Scheduling Process



More Details on Load Following: a measure of system balancing requirements between hour-ahead and the 5 minute dispatch

- The load following capacity requirements for each hour are derived from measures
  - of the differences in each consecutive five minute dispatch interval (ramp rate)
  - of the difference between the average hourly schedules for each hour of the operating day and the maximum deviations from the schedule that take place over any 5 minute dispatch interval within the hour (capacity)

Load Following requirement is shown as the blue shaded area

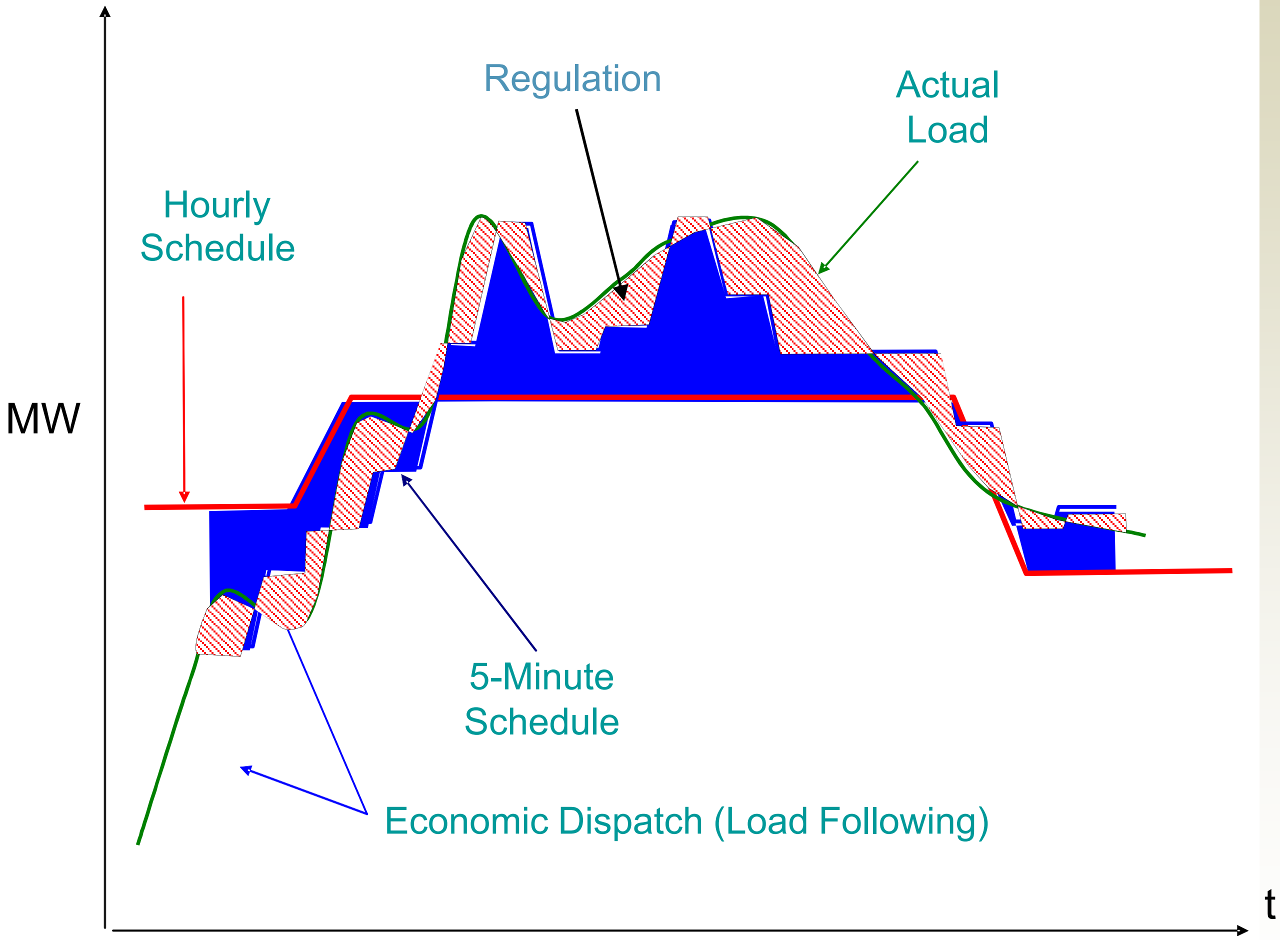


Note : This figure does not reflect an actual scheduling interval

Regulation: A measure of system balancing between the 5 minute dispatch schedule and actual net load

- Regulation is incremental or decremental energy provided through automatic generation control (AGC) on a second-by-second basis for system balancing
- The simulated Regulation requirements for each hour of the operating day are derived from
  - measures of the difference between actual and simulated 1 minute net loads (load minus wind and solar production) between consecutive 1 minute intervals within the 5 minute interval (ramp rate)
  - measures of the maximum difference between the 5 minute dispatch schedules for that hour and the actual minute-by-minute net load in that 5 minute interval (capacity)

Regulation requirement is shown as red shaded area



Note : This figure does not reflect an actual scheduling interval

SECTION 3: COMMON ASSUMPTIONS AND DATA INPUTS INTO ALL MODELING STAGES

All data shown in this section are common inputs to Step 1 and Step 2

- Load profiles for 2020 are used both in the statistical analysis of operational requirements and in the production simulations
- Renewable resource capacity and energy assumptions are the basis for creating renewable production profiles used both in the statistical analysis of operational requirements and in the production simulations

Load Forecast and Profile Assumptions

- Load forecast for 2020 selected by inter-agency team
- Peak Demand in 2020: 70,180 MW (State-wide)
- Peak Energy in 2020: 330,100 GWh
- Minimum Demand in 2020: 23,962 MW
- Hourly load pattern modeled based upon 2005
- Includes adjustment for 2,262 MW of PV on the customer side of the meter that is modeled (in all cases) as a generator to capture the impact of its variability
- Pump storage is not considered as part of the actual load and the load forecast

Renewable portfolios planned to be studied for the 2020 target year

- 20% Renewable Energy Reference Case (33% RPS is not achieved)
- 33% Renewable Energy Cases
  - Reference Case
  - High Out-of-State Case
  - High Distributed Generation Case
  - Low Load Case
- Alternative Case (27.5% RPS Case)
- All Gas; no new renewables after 2008
- These planned set of runs have been modified to reflect the fact that the CPUC has a new set of cases
- Currently plan is to complete 33%, 20% Reference Case and several sensitivities

Renewable Portfolios: *Incremental* Capacity (MW) for 2020 Cases to be Studied and 2009 Renewable Energy (MWh)

	Biogas	Biomass	Geothermal	Small Hydro	Solar Thermal	Solar PV	Wind
20% Reference	30	324	1,052	37	107	333	5,024
33% Reference	279	429	1,497	40	6,513	3,165	8,338
Out-of-State	279	339	2,532	49	1,753 (534 Outside CA)	890	10,870 (6,290 Outside CA)
High Distributed Generation	234	328	1,298	37	1,095	15,959 (15,098 DG)	5,067
27.5%	30	328	1,298	40	4,868	2,864	5,977
Low Load	30	328	1,299	40	4,907	2,867	7,091

	Biogas	Biomass	Geothermal	Small Hydro	Solar Thermal	Solar PV	Wind
Existing (MW-hrs)	0	6,256	13,647	687	724	0	6,229

Renewable Production Modeling – Profiling Approach

- Develop hourly and 1 minute production “profiles” for 2020 for each wind and solar plant
- Year 2005 was used as base year for wind and solar data (as well as load and hydro)
- Profiles for new wind plants based upon NREL wind mesoscale speed/production data for 19 wind sites in CA other states
- Profiles for new solar PV and solar thermal plants based upon NREL irradiance data for 24 sites in CA
- Profiles for existing wind and solar based upon historical data for 2005 when available

SECTION 4:
METHODOLOGY FOR OPERATIONAL REQUIREMENTS SIMULATIONS
(STEP 1)

Contents of Section 4

- Overview of analytical assumptions
- Calculation of forecast errors for load, wind and solar
- Sequencing of operational and market time-intervals
- Simulation methodology and analytical flow
- Types of operational requirement results

Forecast Error Modeling

- Forecast errors are randomly sampled inputs into the operational requirements simulation
- Forecast error distributions draw on
  - Historical data on load and wind forecast errors
  - Modeled data on solar forecast errors
- Additional assumptions are made about the shape of the distributions

Forecast Error Modeling — Solar

- Solar forecast error data is not widely available (due to the few utility scale projects)
- ISO and PNNL developed a solar forecast error model that accounts for
  - Annual and daily patterns of solar irradiance
  - Hour-to-hour clearness index (see next slides)
  - Dynamic patterns of cloud systems
  - Types of solar generators
  - Geographical location and spatial distribution of solar power plants

Forecast Error Modeling — Solar Clearness Index

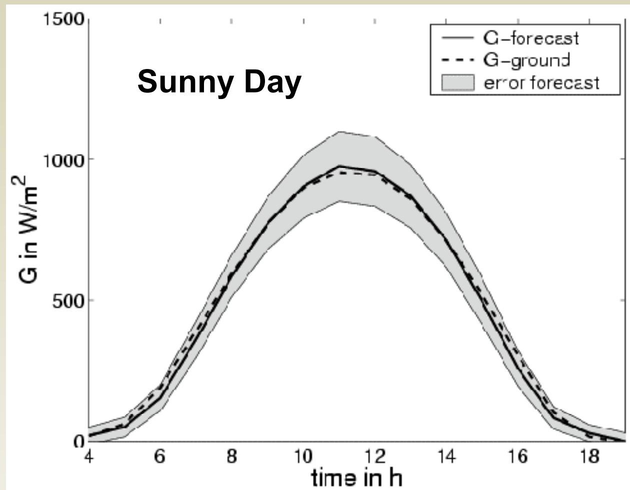
- The clearness index (*CI*) for a given period is obtained by dividing the observed global radiation *Rg* by the extraterrestrial global irradiation *R*:

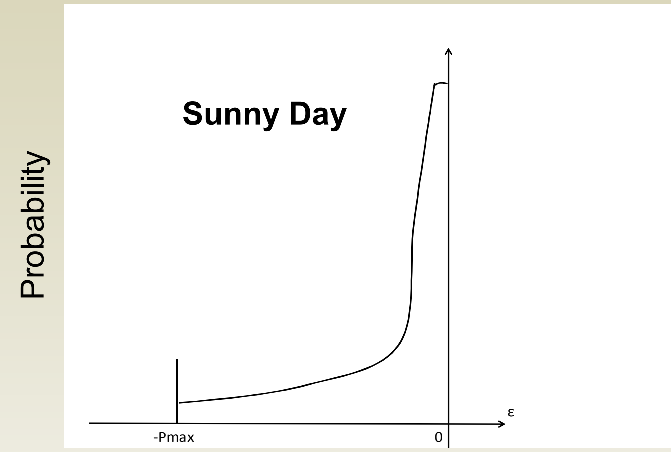
$$k = Rg/R$$

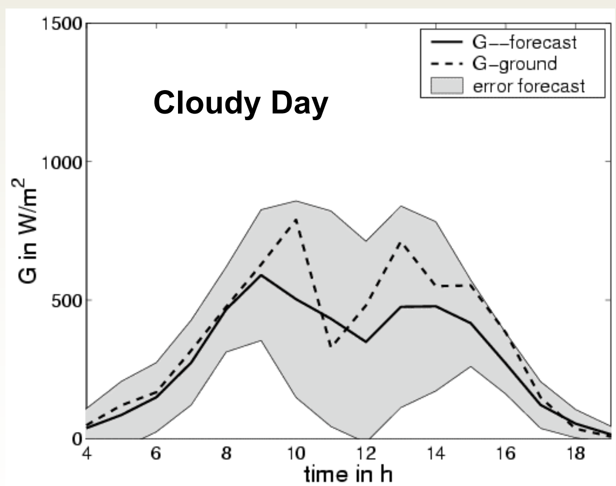
- where *Rg* is the horizontal global solar radiation, *R* is horizontal extraterrestrial solar radiation.
- If the weather condition of a day is between a sunny day and a very cloudy day, the standard deviation of the solar forecast errors will vary.

Forecast Error Modeling — Changes of the solar irradiance error depending on the Clearness Index

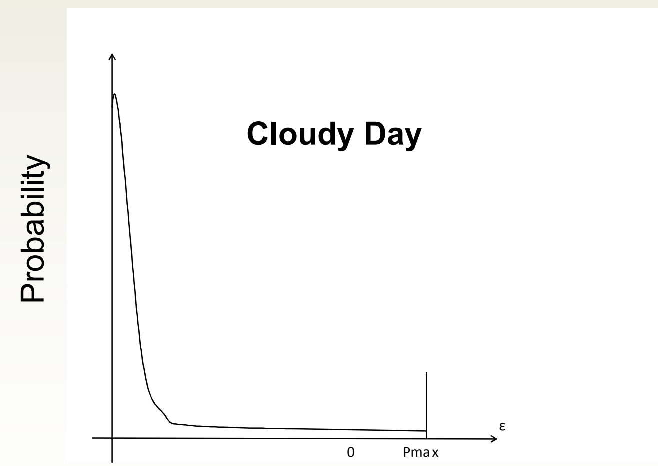
Solar generation forecast error become less significant when the clearness index (CI) is high. Ground measured (solid line) and forecast(dashed) irradiance for a clear sky (top) and a cloudy (bottom) day. The grey area represents ex-pected maximum error of the irradiance forecast.







Forecast Error

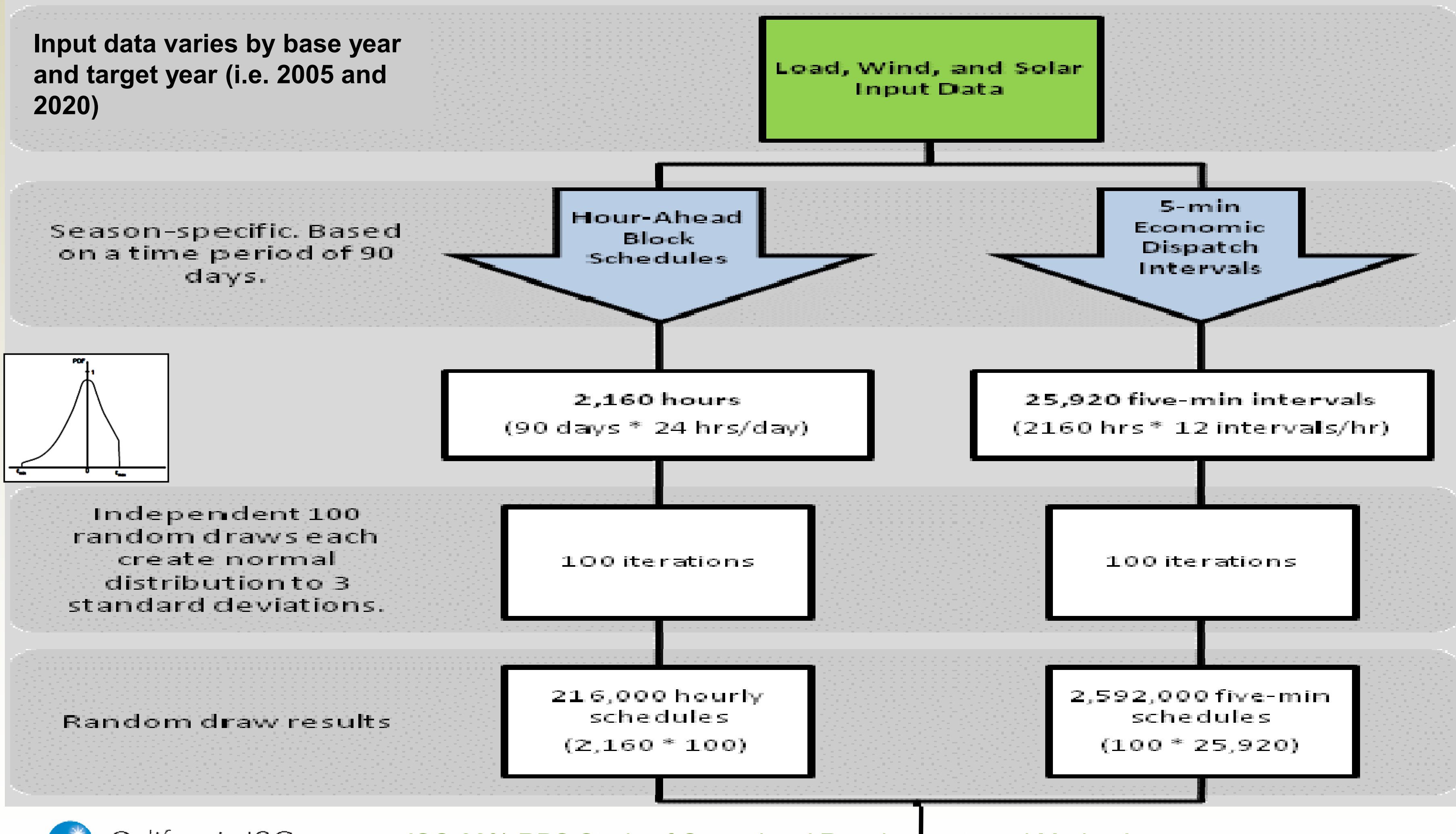


Forecast Error

Methodology to Assess Intra-Hour Operational Requirements

- Monte Carlo simulation that randomly draws realistic hour-ahead and 5 minute-ahead load, wind and solar forecast errors, based on statistical properties of the actual 2005 and projected 2020 forecast errors:
  - Autocorrelation
  - Standard deviation, minimum, maximum & average
  - Truncated normal distribution
  - Persistence for 5 minute errors (wind; solar – using Clearness Index and ramp adjustment)

Flow Chart for Calculating Load Following Requirements



Flow Chart for Calculating Load Following Requirements (cont.)

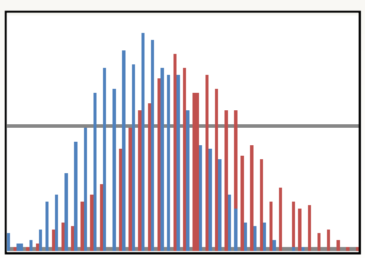
5% max and min of random draw results removed on basis of MW, ramp rate, and ramp duration.

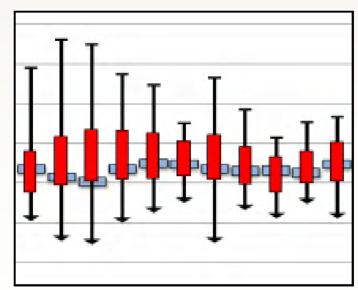
Load Following
Select max deviations across all iterations

NOTE: the term "maximum" used in subsequent slides refers to the 95th percentile value

Frequency Distribution Figures

Whisker, Column Charts

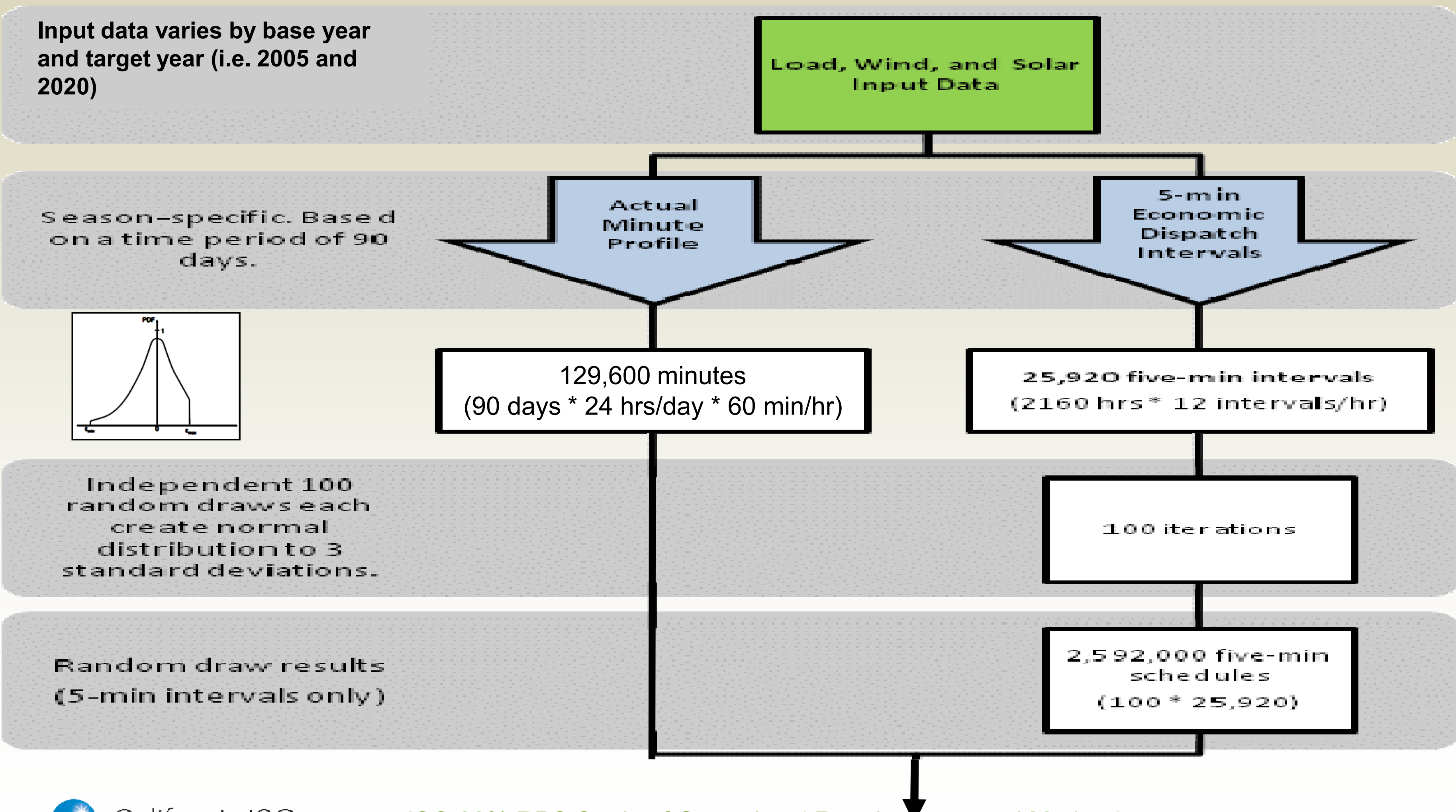




Three Types of Load-Following Results in Both the Upwards and Downwards Directions

- Load following maximum “capacity” requirement for each hour [MW, hourly value]
  - Defined as the largest gap between the simulated hourly schedule and any five minute dispatch interval
  - Input into Step 2 production simulation model
- Load following ramp rate [MW/min]
  - Defined as the largest per-minute change required to meet the load following capacity requirement
- Load following ramp rate duration
  - Calculated ex post as the longest sequence of 5 minute dispatch intervals that sustain a particular ramp rate within any hour or series of hours

Flow Chart for Calculating Regulation Requirements



Flow Chart for Calculating Regulation Requirements (cont.)

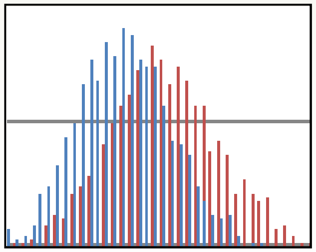
5% max and min of random draw results removed on basis of MW, ramp rate, and ramp duration.

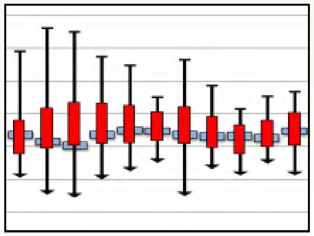
Regulation
Select max deviations across all iterations

NOTE: the term "maximum" used in subsequent slides refers to the 95th percentile value

Frequency Distribution Figures

Whisker, Column Charts





Three Types of Regulation Results in Both the Upwards and Downwards Directions

- Regulation maximum "capacity" requirement for each hour [MW, hourly value]
  - Defined as the largest gap between the simulated five minute dispatch interval and any one minute interval within that five minute interval
  - Input into Step 2 production simulation
- Regulation ramp rate [MW/min]
  - Defined as the largest difference between any two contiguous 1 minute capacity requirements within a 5 minute interval
- Regulation ramp rate duration
  - Calculated ex post as the longest sequence of 1 minute intervals that sustain a particular ramp rate within any regulation 5 minute interval

Varying Forecast Error Assumptions

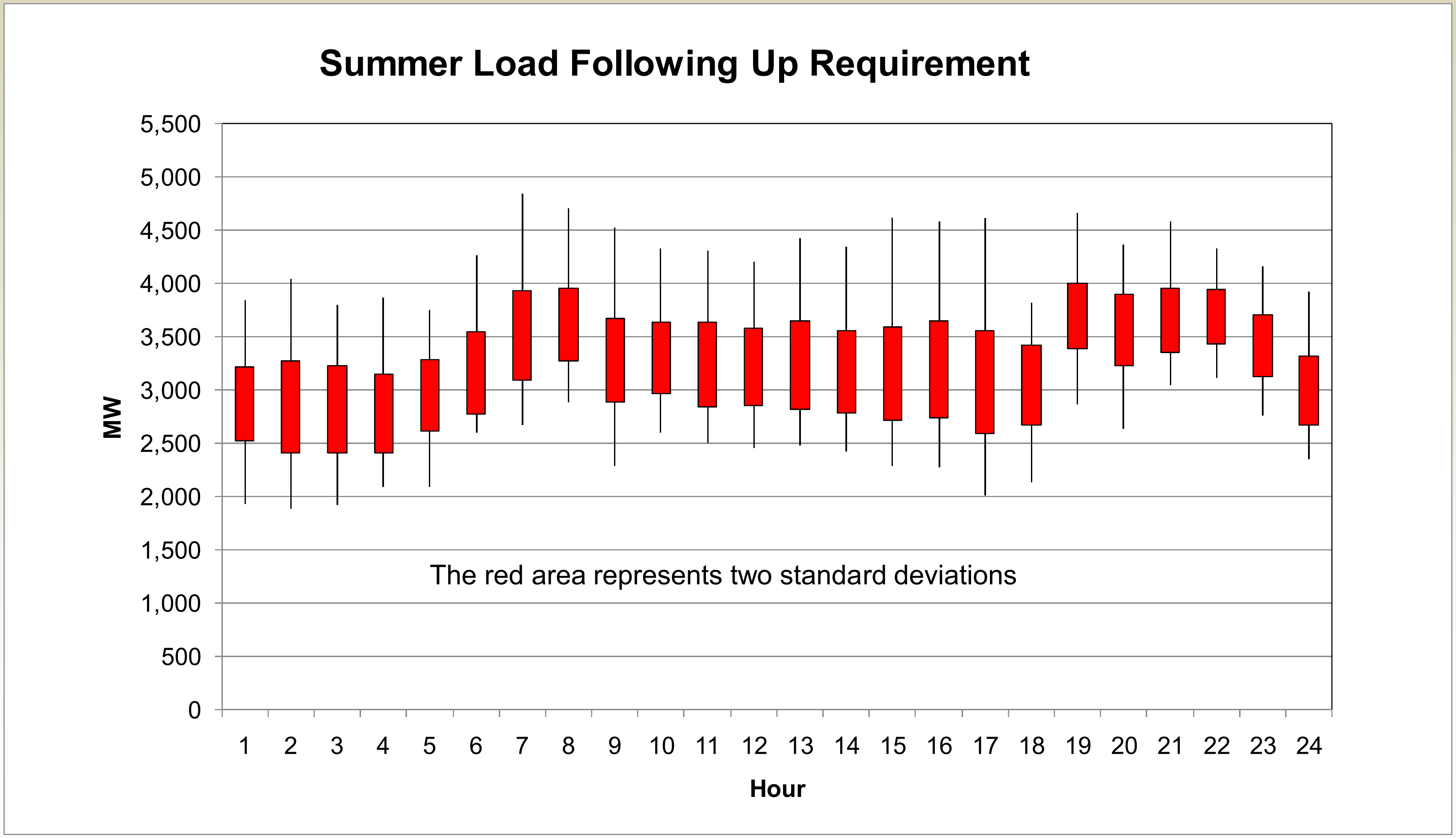
- Methodology allows for varying the shape of the forecast errors for load, wind and solar, or eliminating the errors for one or all of these variables altogether
- Provides insight into the effect of forecast error on the operational requirements
- Changes to all categories of operational measures discussed on previous slides can be calculated

SECTION 5: OPERATIONAL SIMULATION SELECTED RESULTS AND INTERPRETATION (STEP 1)

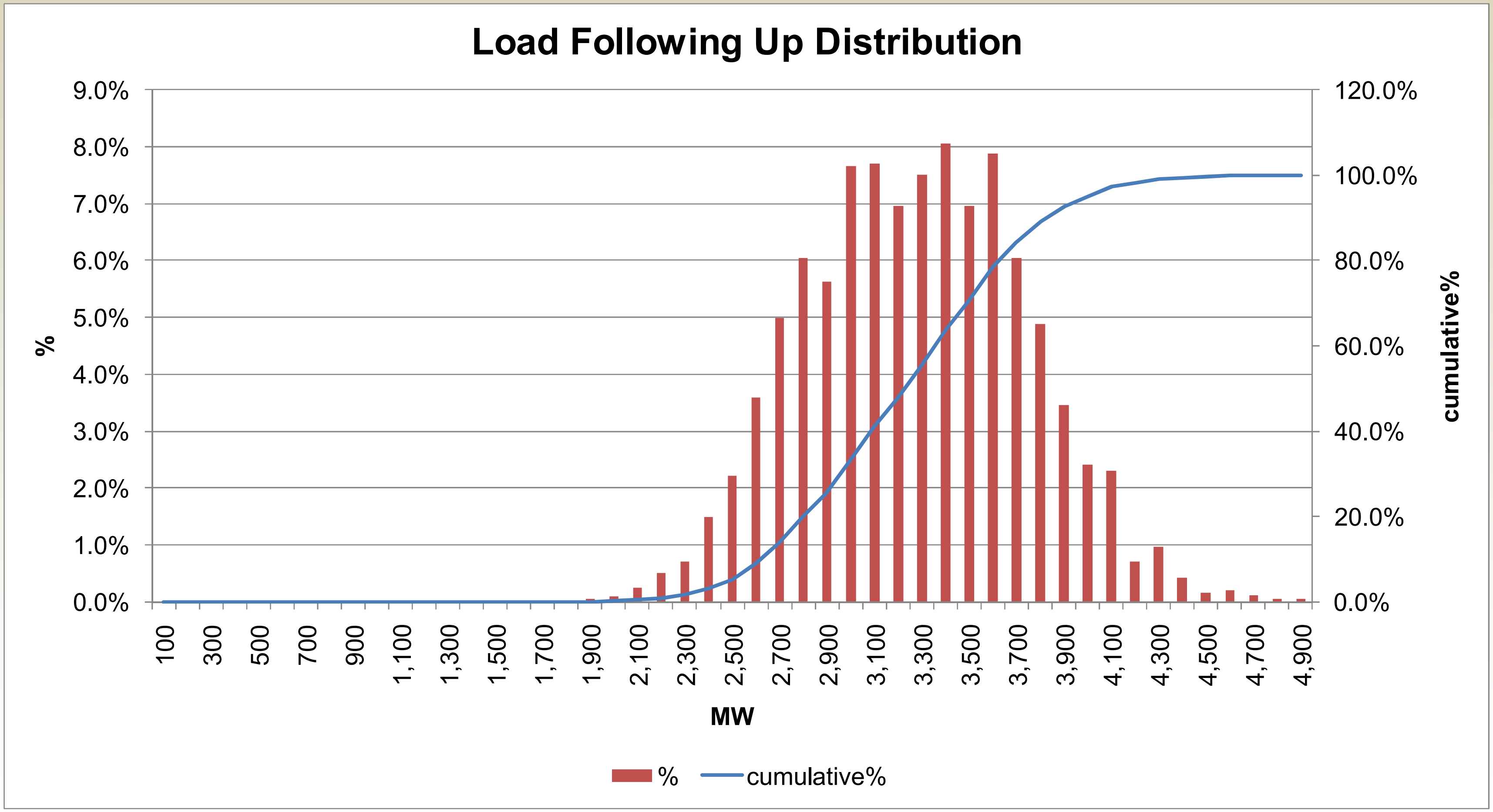
Interpretation of Load Following Results

- Stock charts show the range (minimum, maximum) and average ± one standard deviation for the seasonal hourly results
  - Maximum value for each hour in the season across 100 iterations
- Results are indicative of the potential range of upwards and downwards capability needed in each daily operating hour of the season
- Results assume hour-ahead forecast errors; in the day-ahead market time-frame, ISO will potentially estimate a higher range due to the higher forecast errors

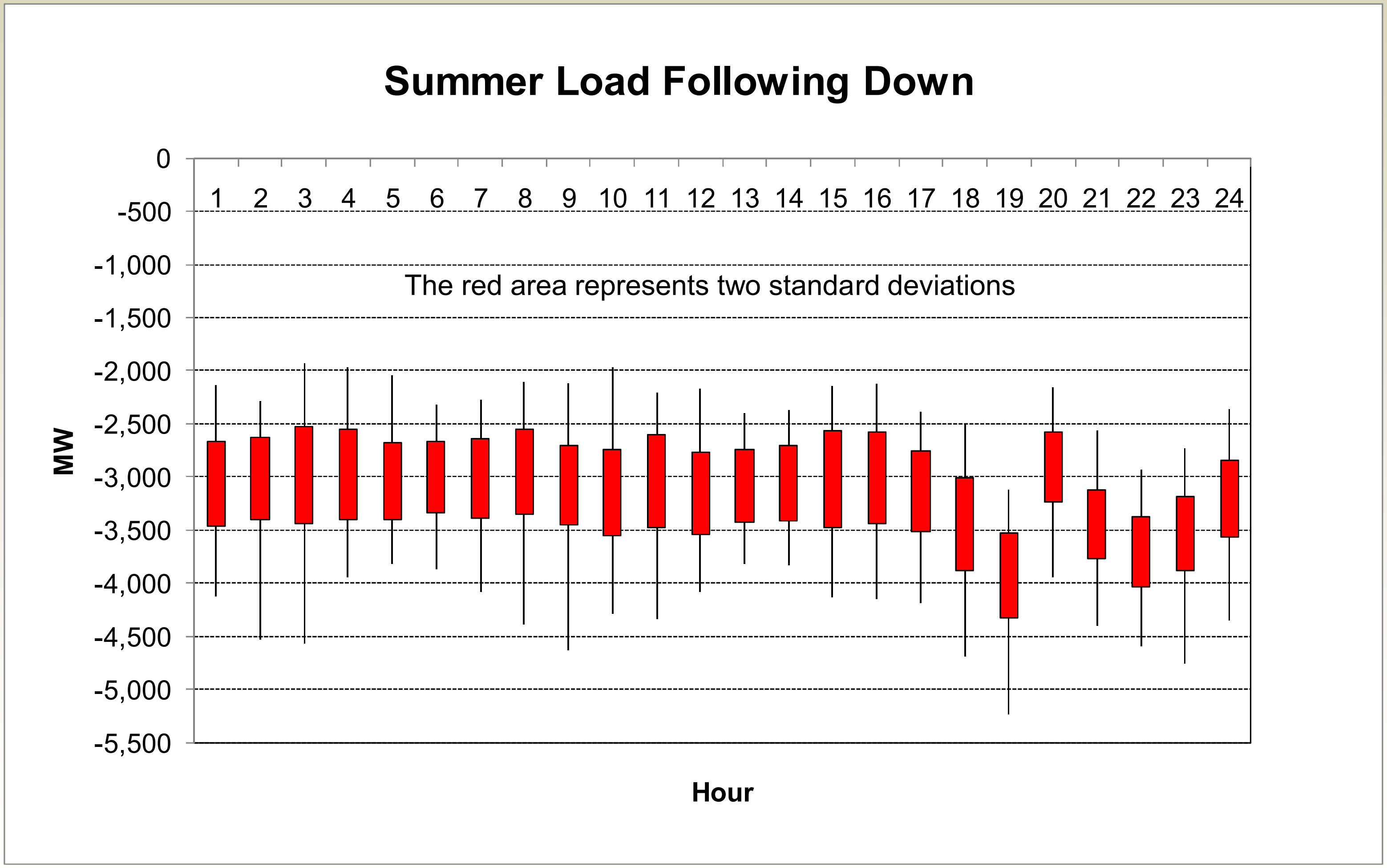
Summer 2020 load following up capacity requirement, distribution of summer hourly results – 33% RPS Reference Case



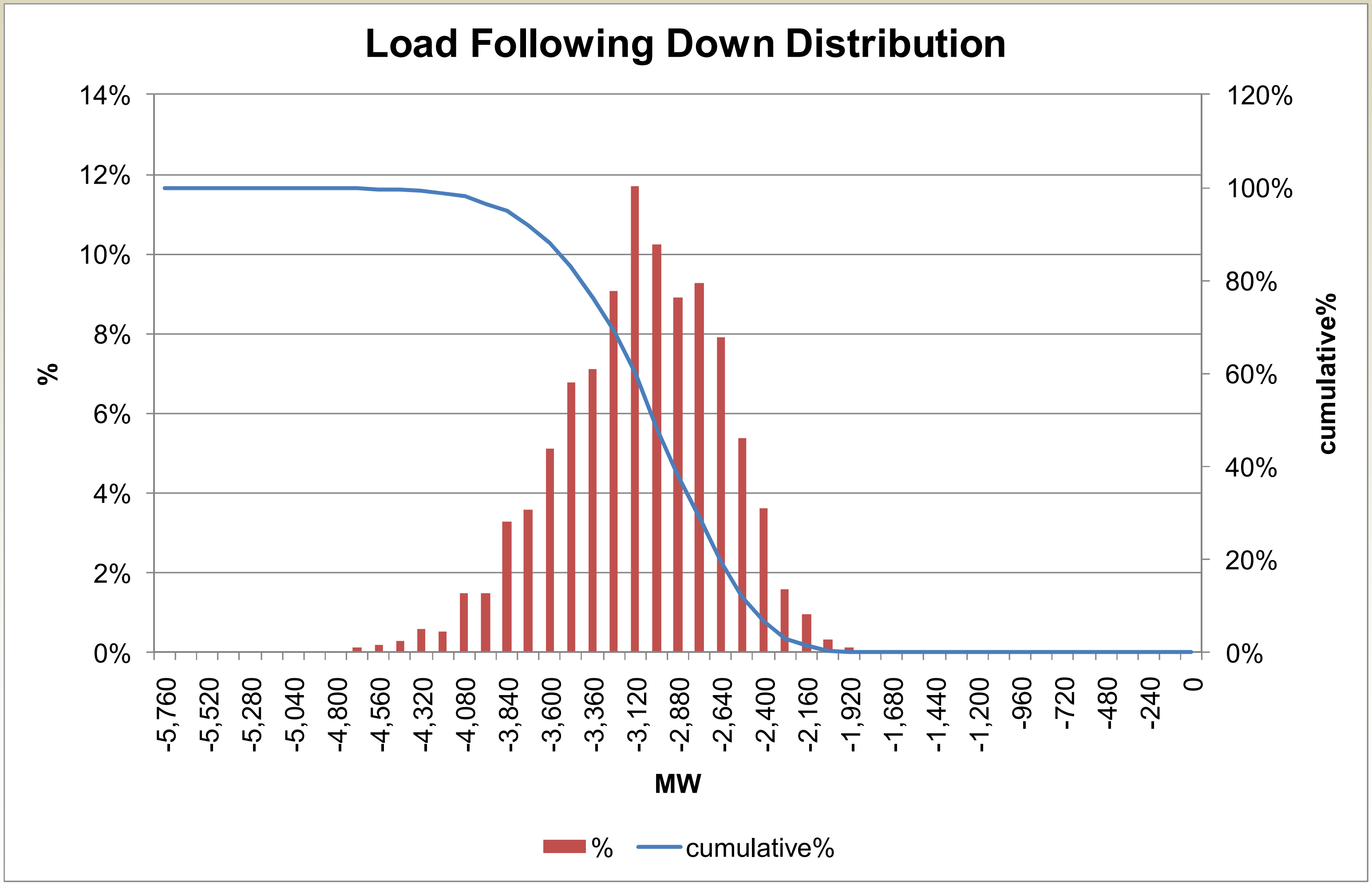
Summer 2020 load following up capacity requirement, frequency distribution of summer hourly results – 33% RPS Reference Case



Summer 2020 load following down capacity requirement, distribution of summer hourly results – 33% RPS Reference Case



Summer 2020 load following down capacity requirement, frequency distribution of summer hourly results – 33% RPS Reference Case



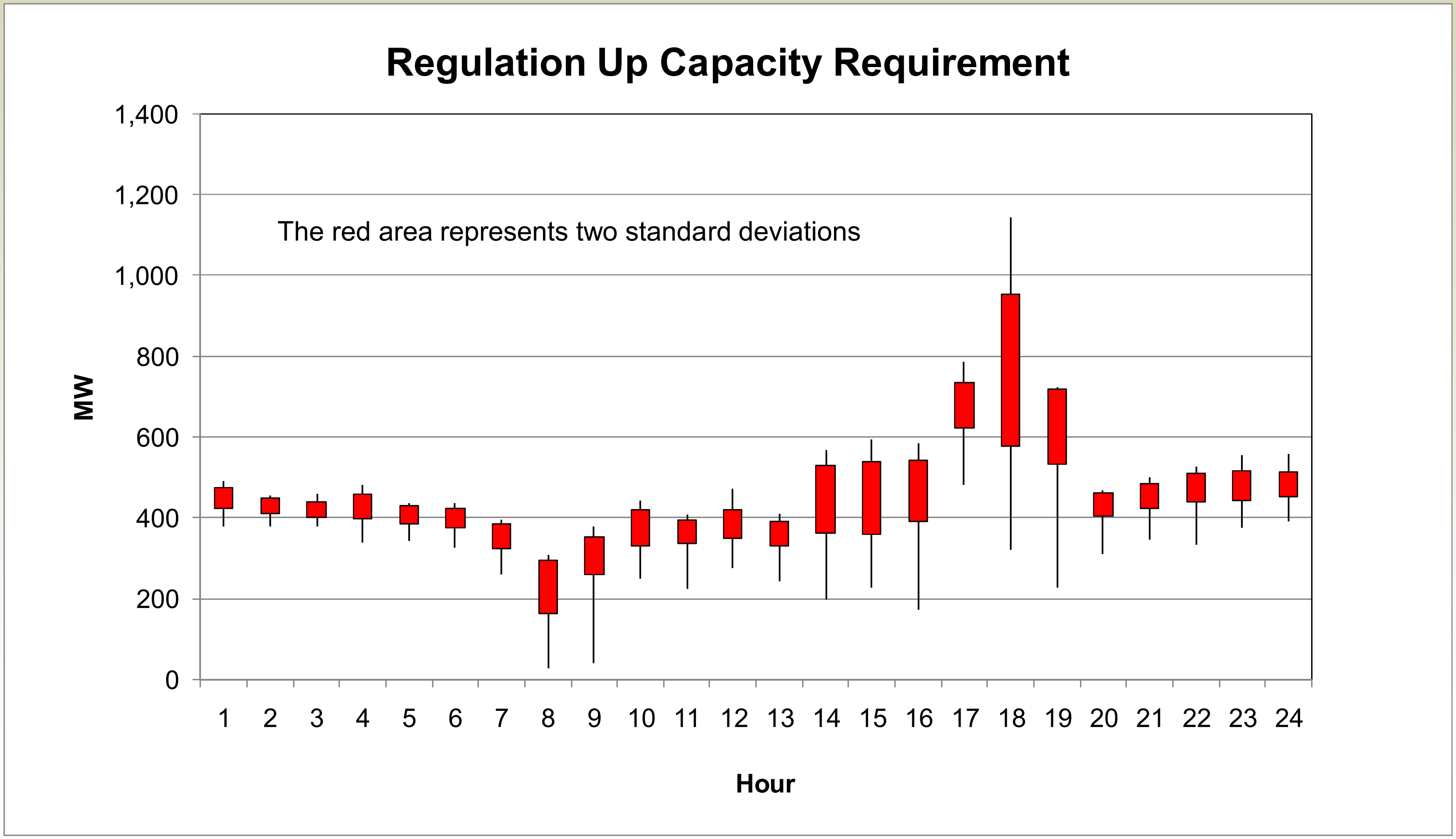
Interpretation of Regulation Results

- Stock charts show the range (minimum, maximum) and average ± one standard deviation for the seasonal hourly results
  - Maximum value for each hour in the season across 100 iterations
- Results are indicative of the potential range of upwards and downwards capability needed in each hour of the season
- Results reflect minute-by-minute variability but assume very short term forecast errors

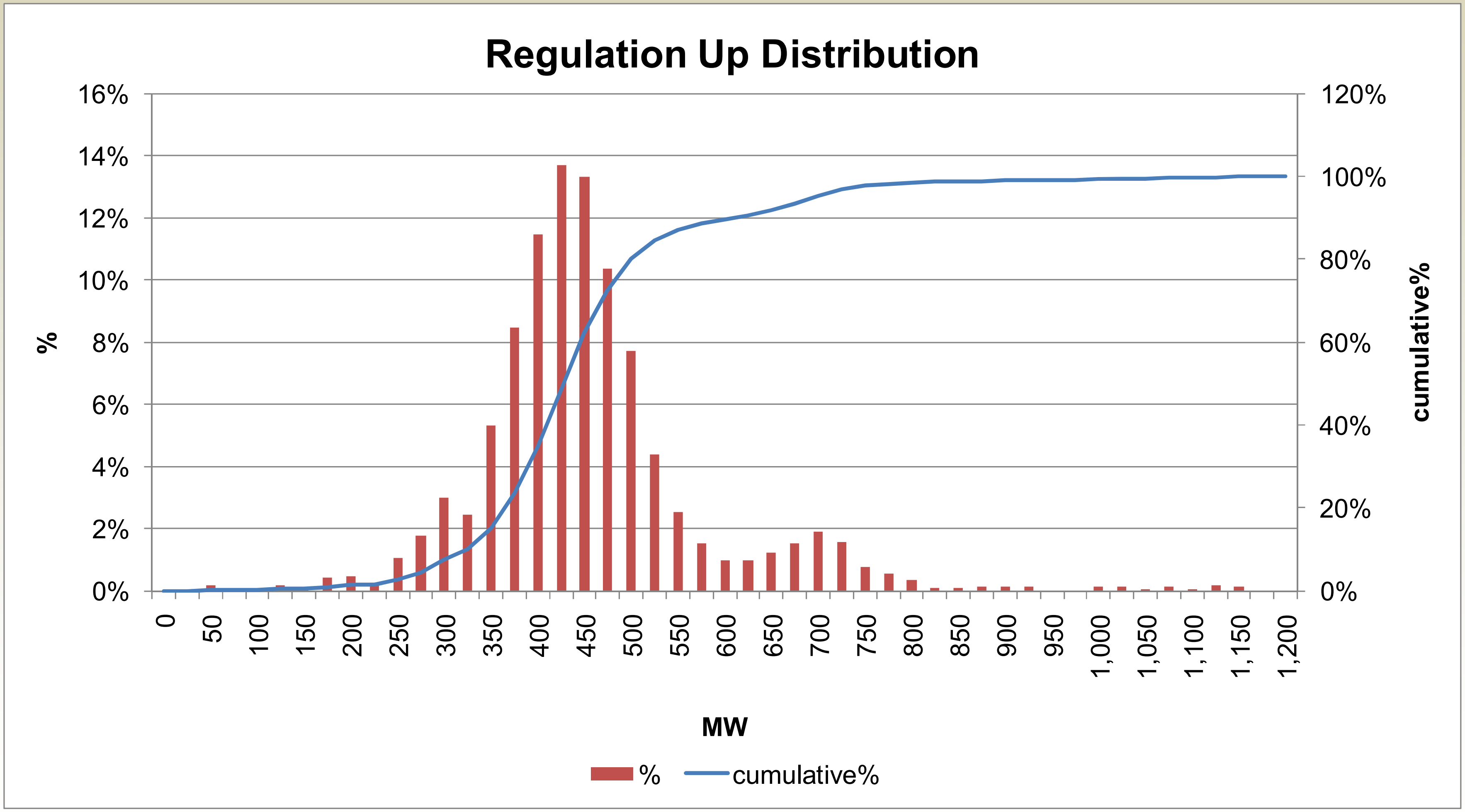
Interpretation of regulation results (cont.)

- In the day-ahead market time-frame, when ancillary services are procured, forecast errors will be larger; hence, ISO will potentially estimate a higher procurement range in that time frame
- Hence, simulation results are possibly closer to a lower bound on regulation procurement

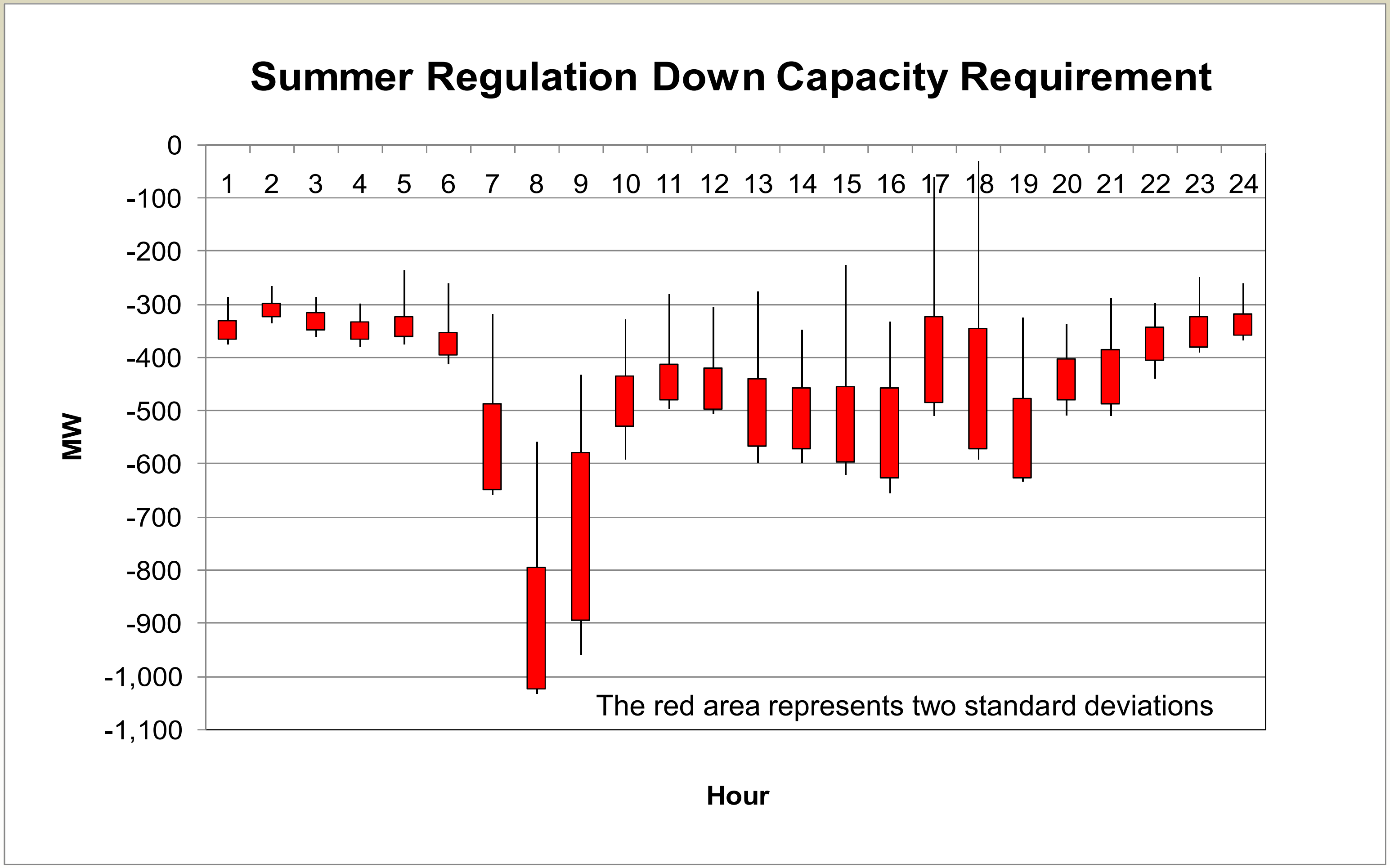
Summer 2020 Regulation Up capacity requirement, distribution of summer hourly results – 33% RPS Reference Case



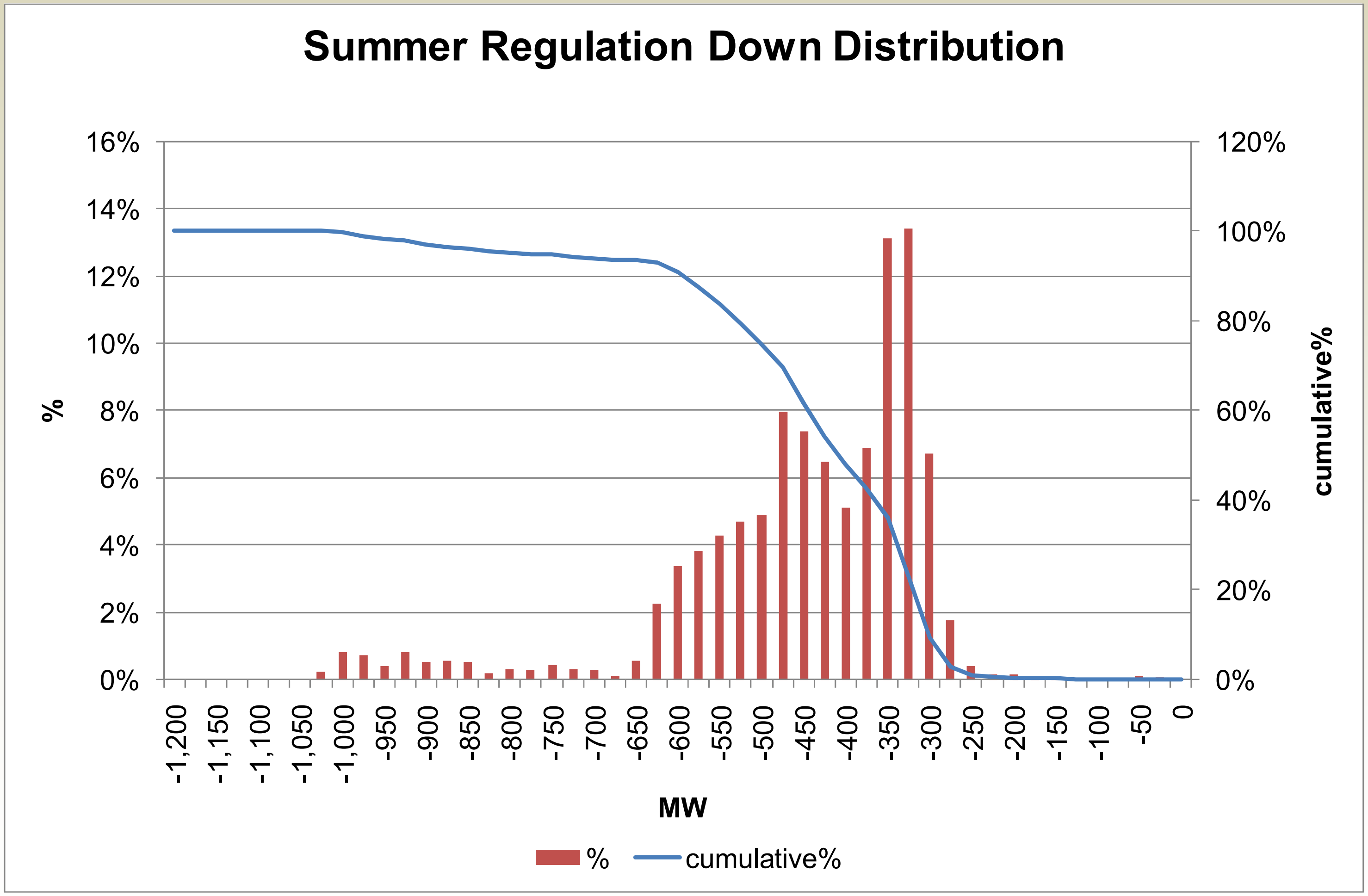
Summer 2020 Regulation Up capacity requirement, frequency distribution of summer hourly results – 33% RPS Reference Case



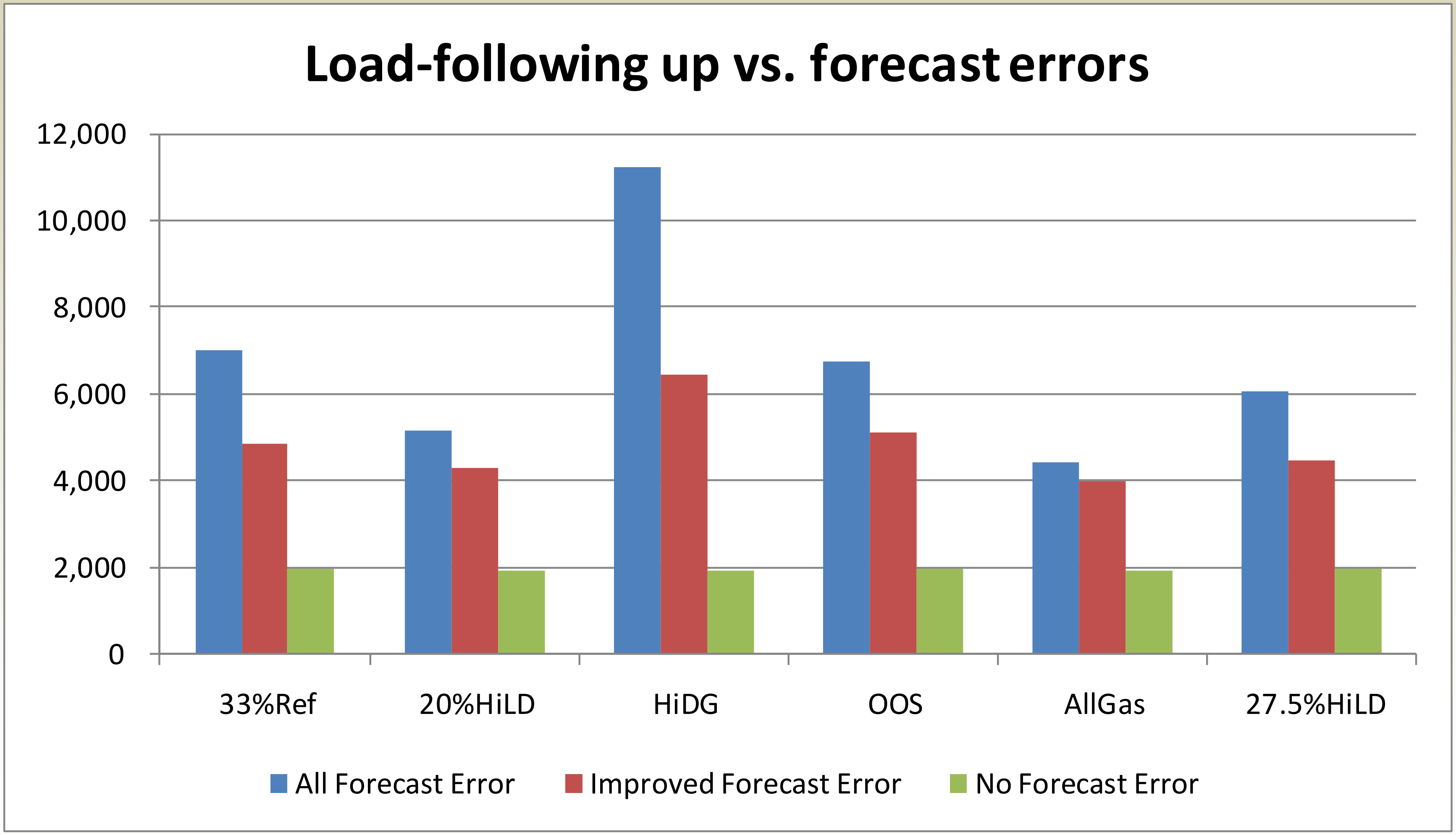
Summer 2020 Regulation Down capacity requirement, distribution of summer hourly results – 33% RPS Reference Case



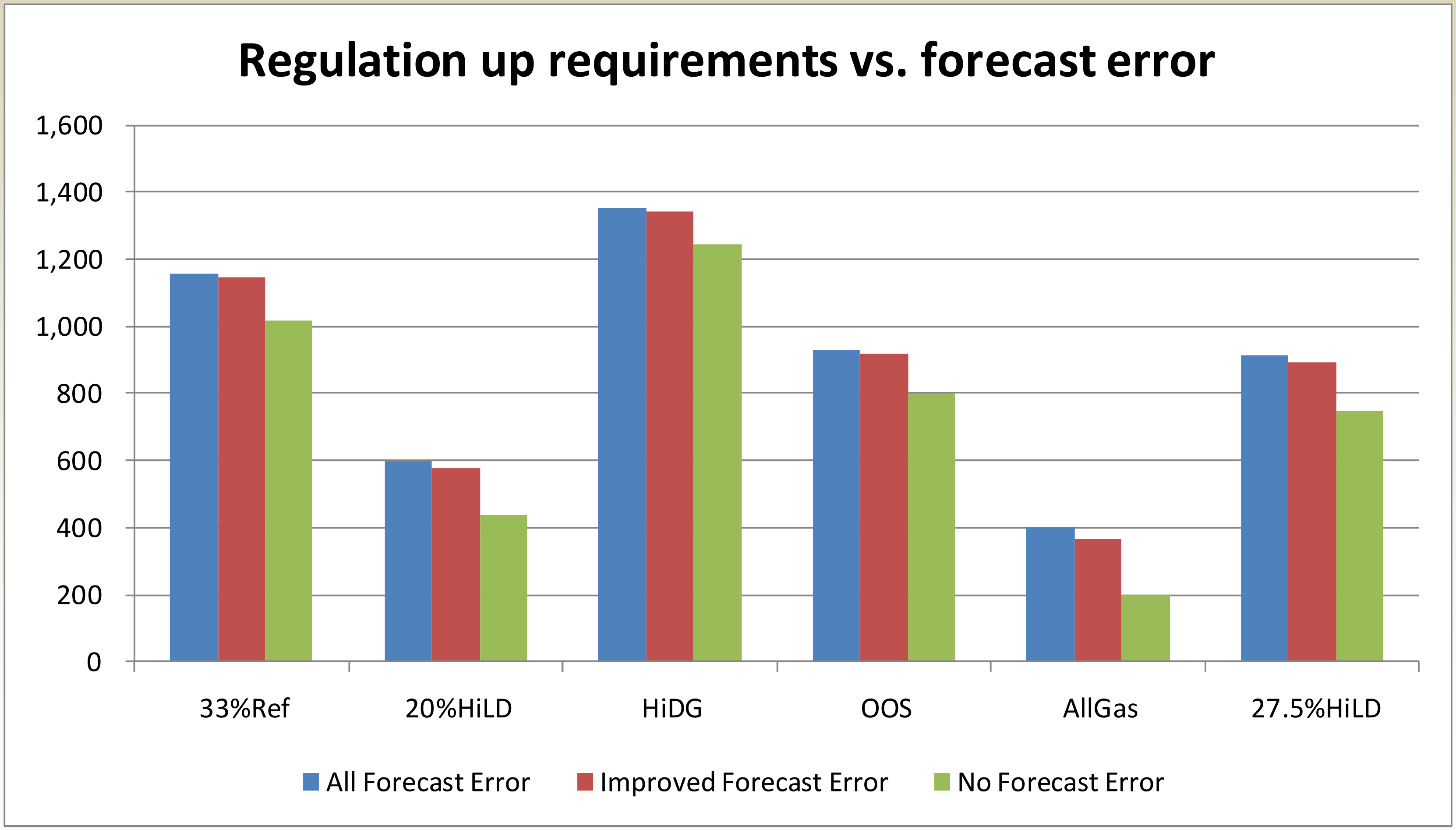
Summer 2020 Regulation Down capacity requirement, frequency distribution of summer hourly results – 33% RPS Reference Case



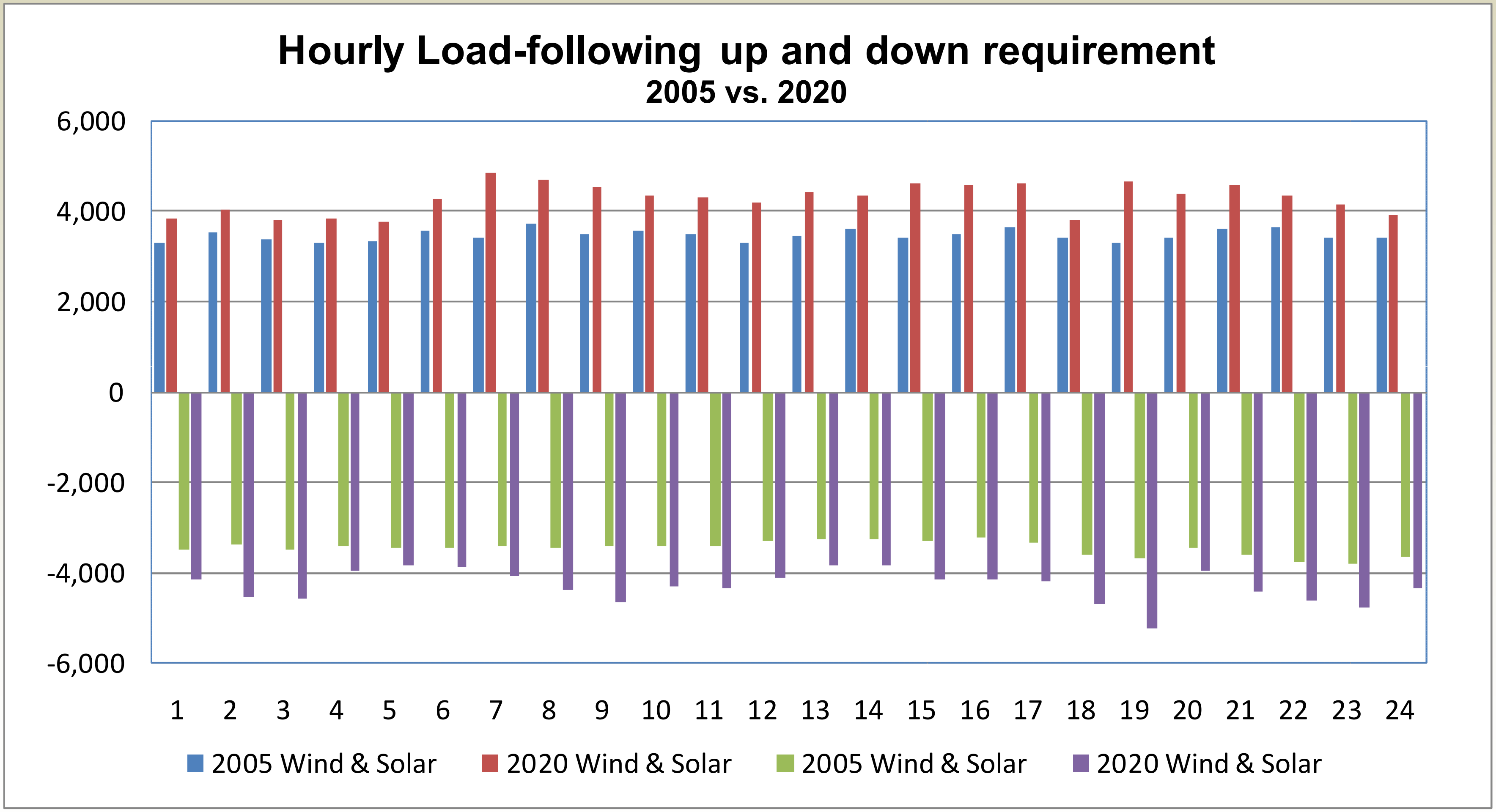
Another representation of the impact on maximum seasonal load-following up requirements under alternative error assumptions, Summer 33% RPS Reference Case



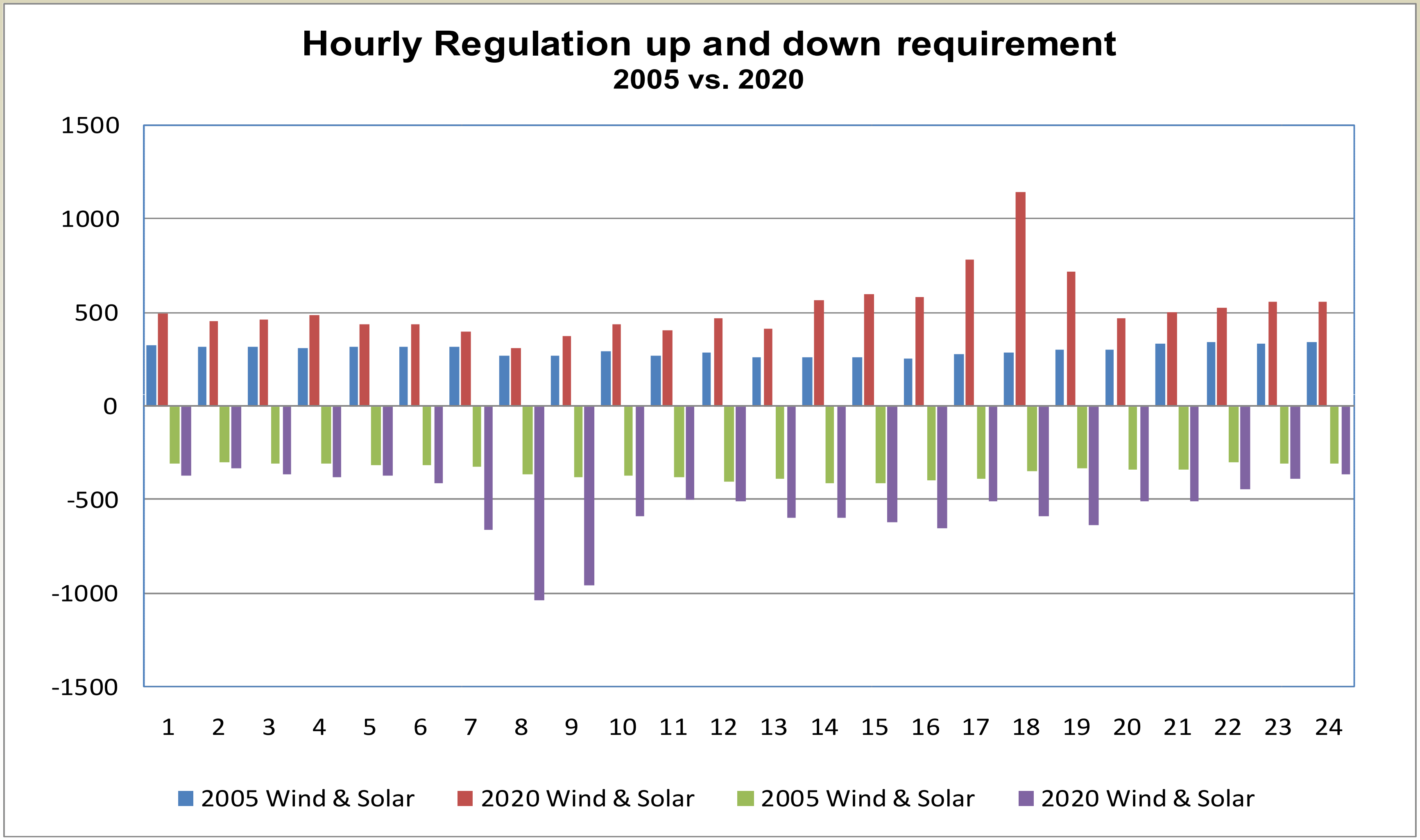
Another representation of the impact on maximum seasonal Regulation Up requirements under alternative error assumptions, Summer 33% RPS Reference Case



Differences in maximum hourly load following requirement between the benchmark year (2005) and the target year (2020) – Summer, 33% RPS Reference Case



Differences in Regulation requirement between the benchmark year (2005) and the target year (2020) – Summer, 33% RPS Reference Case



SECTION 6: METHODOLOGY FOR PRODUCTION SIMULATIONS (STEP 2)

Contents of Section 6

- Methodology and Assumptions
- Development of Generation Portfolios
- Other modeling assumptions

Methodology and Assumptions (1)

- Standard Production Simulation tool used
- Objective: Minimize production costs plus reserve costs
  - Subject to:
    - Power balance constraint (Gen + Imports = Load + Exports)
    - Reserve constraints (regulation, spin, non-spin, load following)
    - Selected transmission constraints (Import, SCIT, Path26, etc)
    - Renewable energy production constraint (33% energy, 20% energy)
    - Resource constraints (minimum up/down, max starts, etc)
- NOTE: Hourly wind and solar profiles and load forecast and profiles used are from same source as Step 1

Methodology and Assumptions (2)

- Production simulation measures “violations” in meeting system requirements
  - Applies penalty factors that ensure that the model commits sufficient existing resources to resolve violations if possible
- These violations include
  - Un-served energy (failure to meet load in a particular hour)
  - Failure to carry reserves (Spinning and non-spinning)
  - Failure to carry needed regulation and load following
  - Overgeneration (energy in excess of load in a particular hour); but model can export surplus renewable energy to rest of WECC
- As discussed in subsequent slides, methodology is to add resource capabilities until all violations, except overgeneration (which is never triggered in the model), are resolved

Development of Generation Portfolios (1)

- Started with TEPPC data base used in CPUC analysis
- Reflected retirement:
  - OTC unit retirements
  - other potential retirements
- Added:
  - planned units
  - economic demand side response
- Select Load Forecast for Energy and Peak Demand for 2020
- Build out renewables to achieve target RPS (e.g. 33% or 20% of forecast energy) (summarized in next slide)
- Determine capacity value of renewables for use in the study (NQCs)
- Add generic units to meet 17% PRM (same % as assumed by CPUC Study)

Development of Generation Portfolios (2) – Renewable NQC Development Process

- Exceedance methodology based upon regulatory approach applied to the 2020 study year
- Used NREL annual (8760 hours) wind and solar profiles for 2005
- Determined NQCs for renewable wind and solar plants using Exceedance methodology (70%) with July hourly production (Peak occurs in July in the study)
- Determine system diversity benefit and allocate to individual plants on a pro-rate basis

Development of Generation Portfolios (3) – NQC Results for 33% Reference Case

Results based upon July production for 33% Reference Case including addition of the system diversification factor

- Existing wind ranges from 2% of nameplate to 30%
- New wind ranges from 1% of nameplate to 8%
- Solar PV ranges from 46% of nameplate to 65%
- Solar Thermal ranges from 91% of nameplate to 99% (result of high capacity factor units from RETI study)

Development of Generation Portfolios (4) – NQC Results for All Cases By Technology

Technology	20% Ref	33% Ref	33% Hi DG	33% Hi OOS
Existing Wind	14%	7%	9%	14%
New Wind	9%	4%	5%	9%
Existing Solar	79%	60%	65%	78%
New Solar PV	75%	56%	64%	65%
New Solar Thermal	100%	96%	99%	100%

Average NQC as a percent of nameplate

Development of Generation Portfolios (5) – Assumptions about Resources External to California

- Started with TEPPC data base used in CPUC analysis which included generation, load, inter-utility transmission constraints and renewables in 2020 (must check this with SCE)
- Unlike California, A/S requirements were not modeled for operation external to California
- Existing set of resources were supplemented with conventional resources when local planning reserve margins were found to be lower than WECC summary
- Unlike California, generation performance modeling was not further refined based upon BA data and experience and owners insights

Development of Generation Portfolios (6) – OTC Retirements Assumed (14,295 MW)

Unit	NQC (MW)	Control Area
Harbor	237.5	LDWP
Haynes 1-6	1570	LDWP
Scattergood 1-3	803	LDWP
Contra Costa 6-7	674	PG&E_BAY
Pittsburg 5-6	629	PG&E_BAY
Potrero	206	PG&E_BAY
Humboldt Bay 1-2	135	PG&E_VLY
Morro Bay 3-4	650	PG&E_VLY
Moss Landing 6-7	1510.03	PG&E_VLY
Alamitos 1-6	2010.38	SCE
El Segundo 3-4	670	SCE
Huntington Beach 1-4	901.55	SCE
Mandalay 1-2	430.29	SCE
Ormond Beach 1-2	1516.27	SCE
Redondo Beach 5-8	1343.01	SCE
Encina 1-5	946	SDG&E
South Bay 1-4	693	SDG&E

Development of Generation Portfolios (7) – Other Unit Retirements Assumed (1406 MW)

Unit	NQC (MW)	Control Area
ELCAJNGT_1	16	SDG&E
Ellwood1	54	SCE
Kearn2AB1	14.75	SDG&E
Kearn2AB2	14.75	SDG&E
Kearn2CD1	14.75	SDG&E
Kearn2CD2	14.75	SDG&E
Kearn3AB1	15.25	SDG&E
Kearn3AB2	15.25	SDG&E
Kearn3CD1	15.25	SDG&E
Kearn3CD2	15.25	SDG&E
KearnGT1	16	SDG&E
GWFTracy1	84	PG&E_VLY
GWFTracy2	83	PG&E_VLY
Los Esteros	186	PG&E_BAY
Mandalay 3	130	SCE
Miramar1	18	SDG&E
Miramar2	18	SDG&E
Pittsburg 7	682	PG&E_BAY

Development of Generation Portfolios (8) – Planned Unit Additions Assumed (9404 MW)

Unit	NQC (MW)	Control Area
Contra Costa Repower 1-2	586	PG&E_BAY
Gateway	530	PG&E_BAY
Humboldt Bay Repower	163	PG&E_BAY
Los Estros Calpine	320	PG&E_BAY
Mariposa	184	PG&E_BAY
Marsh Landing	720	PG&E_BAY
Russel City	600	PG&E_BAY
Colusa	660	PG&E_VLY
GWF Tracy CCGT	314	PG&E_VLY
Moss Landing 1-2	1020	PG&E_VLY
Panoche	400	PG&E_VLY
Starwood	111	PG&E_VLY
El Segundo Repower	530	SCE
Inland Empire	672	SCE
Oxnard Peaker	46	SCE
Riverside Energy Center	96.85	SCE
Sentinel 1-8	728	SCE
Walnut Creek 1-5	479	SCE
Carlsbad Energy Center	558	SDG&E
Orange Grove	96	SDG&E
Otay Mesa	590	SDG&E

Thermal Resource Modeling Assumptions (Cont'd)

- Planned Unit Additions (9,404 MW)
  - Most of the planned units have a CPUC approved contract
  - Additional units assumed online for local system needs
- Generic Unit Additions to meet PRM (Scenario-dependent)
  - All generic units added to the system are peaking units (same as CPUC assumption)
  - Generic capacity need determined based on shortage from meeting PRM
    - Units are first placed in control areas with high OTC retirements
    - Remaining generic capacity is distributed proportionately to load in PG&E, SDG&E and SCE

Demand Response Modeling Assumptions for 2020

DR Final Assumptions for 2,800 MW

Type	Capacity* (MW)	All Year Rating (MW)	Summer Rating (MW)	Strike Price	Minimum Up Time (hours)	Max Times per day	Limits	Non-Spin Capability (MW)	Max Non-Spin (MW) ***	Hour Restrictions
Highest Cost	1/3 of total: 933	311	622	1000 $/MWh	4	1	None	No non spin provided	0	NA
Medium Cost	1/3 of total 933	311	622	600 $/MWh	4	1	20 hours / month	25% of summer capable plants can provide non spin (hours 12-18) with ramp rate of 3% per minute	46.7	Only available hours 12-18
Lower Cost	1/3 of total 934	311	622.7	Price below highest cost unit**	1	1	Max 2 hours / day	50% of summer capable plants can provide non spin (hours 12-18) with ramp rate of 3% per minute	93.4	Only available hours 12-18

* For each DR type, 2/3 capacity available in the Summer months only and 1/3 year round

** Priced at 17,000 HR

*** Non-Spin based on amount available in 10 minutes

DR split based on regional share of load (North and South)

	Peak Load (MW)	Share of DR
PGE_VLY	10,583	22.5%
PGE_BAY	10,583	22.5%
SCE	25,939	55.1%

California Resource Summary for 33% RPS Reference Case

Resource Category	Capacity (MW)	Energy (GWh)
Total Existing Resources (2020)	**56,450**	
Thermal	23,047	**Dispatchable**
Cogeneration	4,358	**35,409**
Hydro	7,227	**33,924**
Pumped Storage	3,057	**Dispatchable**
Renewables	2,897	**27,542**
Demand Response	2,863	**Dispatchable**
Net Interchange	13,000	**Dispatchable**
Total Unit Retirements	**16,331**	
OTC	14,925	
Other	1,406	
Planned Unit Additions	**21,995**	
Planned Thermal	9,404	**Dispatchable**
DR	937	**Dispatchable**
Incremental Renewables	11,654	**67,348**
Generic Thermal Additions	2,343	**Dispatchable**
TOTAL RESOURCES (2020)	**80,787**	

Ancillary Service Modeling Assumptions

- Four individual operational requirements are modeled
  - Regulation (Up and Down) – automatic generation control
  - Load Following (Up and Down) – predictable intra-hour load variations
  - Spin – operating reserves, synchronization required
  - Non-Spin – operating reserves, with no synchronization required
- Assume that future A/S provision is based on current market practices
- Statewide requirements split between CAISO units and Muni units based upon their respective loads

Modeling of Balancing for Out of State Renewables

- Two types of arrangements modeled for meeting the within-the-hour balancing requirements for Out Of State renewables:
  - Supplied by source Balancing Authority and scheduled to CAISO on an hourly basis
  - Balanced by CAISO similar to a dynamic schedule arrangement
- Assumed split of balancing responsibility

Case	OOS Wind	OOS Solar Thermal	Balanced by CAISO	Balanced by Source BA
33% Reference	3,302	534	20%	80%
High Wind	3,302	534	20%	80%
High OOS	6,745	534	30%	70%
High DG	3,302	534	20%	80%
20% Reference	1,902	0	0%	100%

Generation Constraint Modeling Assumptions

- Unit provision of reserves, regulation and load following is constrained by the unit's ramp rate and its available unit capacity
- Time frames:
  - Reserves and regulation are 10 minute products
  - Load Following is modeled on a 20 minute basis
- Limited unit rate ramp sharing is allowed when a unit is providing load following and Regulation simultaneously; otherwise ramp rate sharing is not allowed
- Inter-hour changes in generation to meet the hour to hour changes in net load are also independently checked by the Plexos software; these check are made assuming a 20 minute period to move from one generation level to the next generation level in the following hour
- This Plexos check ensures that the units moved can do so in 20 minutes given their unit ramp rate

Transmission Constraint Modeling Assumptions

- Import Limits for SCE (70%/30%) and SDG&E (75%/25%) areas
- These limitations constrain hourly imports from outside these service areas to be less than or equal to 30% of the hourly load for SCE and less than or equal to 25% of the hourly load for SDG&E
- Imports/Exports limited only by line transfer capacities in base modeling except for SCE and SDG&E import limits
- Total CA import limitation of 13,339 MW

Hydro Modeling Assumptions

	PG&E and SMUD		SCE	
	Run of River	Dispatch	Run of River	Dispatch
Energy (GWh)	5,285	23,322	904	4,854
NQC (MW)	940	5,627	181	899

- Dispatchable hydro modeled with weekly constraints on energy, max capacity, min flows, ramp rates and A/S provisions
- Based upon 2005 hydro year
- Hydro dispatch is constrained to maintain current operating conditions

SECTION 7:
KEY SIMULATION OUTPUTS
AND
STATUS OF RESULTS

Process to Develop Resource Needs Using Step 2 Results

- The results of each case are used to determine the resources required to operate the system (under simulation) without violations
- The amount of resources required above resources needed to meet PRM are counted as integration needs
- The amount of resources required for integration is informed by the difference in resources required for a 33% case and the resources required for a reference case – e.g. the 20% Reference or the All Gas Cases
- This difference is an indication of resources required to meet the system integration needs; additional resource types will matter less than the capabilities that are provided

Methodology to Calculate Integration Costs (1)

- Study method can determine cost of integrating the renewables in the 33% Reference Case that are not in the 20% Reference Case
- Integration cost = fixed costs + variable costs
  - Fixed costs are the capital costs of the resources needed in the 33% RPS Reference Case above those needed to meet PRM less the resources needed in the 33% Case above those needed to meet PRM
  - Variable costs = Production cost difference between 33% and 20% minus credit for fossil energy displaced by the incremental renewable energy; propose to use a range of credits resulting in a range of integration costs

Methodology to Calculate Integration Costs (2)

- Credit for energy displaced = hourly market clearing price (MCP) × change in renewable energy
- Range of credits: propose to use two sets of MCP to develop range; one MCP from 33% Reference Case and the other from the 20% Reference Case
- Range of integration costs: Established by fixed cost plus production costs difference minus two credits for displaced energy (20% and 33% renewable energy)

Status of Phase 1 Results and Next Steps

- Base Step 1 Analysis is complete, additional sensitivity analysis planned while Step 2 work proceeds
  - Sensitivities to be informed in part by frequency distribution of the requirements (as included in this presentation)
- Step 2 Analysis for 33% Reference Case
  - Modeling largely complete
  - Run to eliminate violations completed
  - Some sensitivities underway and others planned

Status of Phase 1 Results and Next Steps

- Sensitivity areas planned
  - Range of Load Following requirements
  - Range of exports from California
  - Variations in ramp time requirements
  - Evaluate frequency distribution of results
  - Variation in results with different renewable capacity values and PRM values
- Step 2 Analysis for Remaining Cases will follow to support calibration of overall results
  - Complete 20% Reference case for comparison, plus sensitivities
- Finalize cases to be performed that are based on latest RPS scenarios

Questions

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